DWR Power Contract Modeling

10 Year Load and Supply forecast Analysis

Data Sources

PGE:

Data used: PG&E provided monthly GWH for 2001 – 2003 for average and dry year.
PG&E hourly load data for 1999 pulled off of FERC website – to create hourly load shape
NP 15 hourly resources for 2000 provided by ISO – to create hourly resource shape

Base Years: Load – 1999 FERC data
Supply – 2000 ISO data

Escalation: PG&E provided annual Mwh for 2001 – 2003. For the follow on years, annual Mwh for 2001- 2009 were pulled off the FERC website. The escalation was calculated, and this escalation was added onto the PGE forecasted load for 2003. Supply was held constant from 2003 to 2010.

SCE:

Data Used: SCE provided hourly data for 2001 – 2005
Base Years: Load and supply used 2005
Escalation: SCE provided load escalation factors from 2001 to 2010. Supply was held constant at the 2005 level.

SDG&E:

Data Used: SDG&E provided hourly data for 2001 – 2003
Base Years: Load and supply used 2003
Escalation: Used the SCE provided load escalation factors to escalate the 2004 through 2010 annual Mwh. Supply was held constant at the 2003 level

Other assumptions:

Below Normal Hydro Year for 2001:

We wanted to create a below normal hydro year. This was done by taking one third of the difference of a normal and dry year and subtracting it from the normal year. Normally a reduction in hydro resources does not effect load, but PG&E has a contract with WAPA in that they make up for WAPA contracted supply when hydro resources fall short. This causes the PG&E load to increase in a dry year. This was taken into account as well.

SCE's hydro resources were reduced as explained for PG&E above.. SDG&E does not have any hydro resources, so no change was made.

San Onofre Nuclear Generating Station (SONGS) outage:

The SONGS plant experienced a fire that had shut down one of its reactors until June 1, 2001. SCE already had this included in their hourly resource data. SDG&E did not. We corrected the SDG&E data to adjust for this reduction in utility retained generation (increase in net short energy).

Hourly Load and Supply Forecasts

Using the above data, a 10-year load and supply forecast was created for each of the three utilities. Using the base year a factor was created by dividing each hourly load by the total load for the year. This created 8,760 factors. For each forecasted year, the total Mwh forecasted for that year was multiplied by the hourly factor to create a stream of 8,760 data points for each year.

The goal was to create an average week, so it was important that the forecasted weekday line up with the base year weekday. Starting with January 1 of the forecasted year, the total Mwh of the forecasted year was multiplied by the factor for the first day in the base year with the same weekday. For example, with a forecasted year of 2001 and a base year of 1999: January 1, 2001 was a Monday, so the factor from January 4, 1999 was used which was the first Monday of that year.

This created a problem at the end of the year. There needed to be additional days added onto the end of the base year to create factors to multiply out the last days of the forecasted year. The last 7 days in December was duplicated to accomplish this. This created another problem since the last 7 days of December always started with Dec 25, Christmas, which is a holiday. To remedy this, the next closest weekday, which was the same weekday as Dec 25 was used to start the additional week added on to the base year. To finish off this "added" week, the last 6 days of December were used. Using the same example of a base year of 1999 and a forecasted year of 2001. December 28, 2001, a Thursday matched up with December 31, 1999. There are still 3 days in 2001 to be forecasted. The last week of 1999 was duplicated at the end, but this put December 25 as the next day. December 25 is a holiday, and since we needed a Friday day represented, we took the next previous Friday, December 18, 1999. For the next day, Saturday, December 26, 1999 was used.

This is the only accounting for holidays that was done, and it was only done in this case since we were already making changes for those days.

Hourly supply numbers were created similarly.

Typical Week, and Maximum Day Forecasts of Load and Supply

SCE and SDG&E forecasts were combined to create the one SP15 forecast. PG&E's forecast became the NP15 forecast. A profile of the typical week for each month for 120 months was created. A week has 168 hours in it, if hour 1 on Sunday is hour 1 and hour 24 on Saturday is hour 168, then all the hour 1's were averaged in each month, all the hour 2's were averaged in the month and so on.

In addition to the typical week, the maximum day for the month was modeled. Both of these curves were superimposed on top of each other, so while one could see the typical week, the maximum day for the month was also seen allowing the contracting team to know what amount of capacity would be needed to meet the maximum forecasted load for that month.

Adjustments to Load and Supply

Taking the forecasted IOU load and supply, toggles were put in place to allow these forecasts to be modified as forecasts and analysis dictated:

IOU Total Load:

Voluntary Conservation: Total Load was reduced by 4% in 2001 and to a lesser extent in the remaining years. This was based on a 7-8% actual reduction in load due to consumer conservation in Feb 2001 as compared to Feb 2000.

Price Elasticity: Total Load was reduced by an additional 3% in 2001 and to a lesser extent in the remaining years based on a known Price Elasticity of Demand of 6% for a 30% rate hike.

IOU Total Supply:

QFs: IOU QF Resources were reduced by 34% in March, 34% in April, 17% in May and 10% in June 2001 and thereafter based on an actual reduction in QF generation in February of 34%. QFs were not expected to return to their full output, and so 10% QF reduction was maintained for the remaining years

CERS Power Transaction Modeling

Transaction Entry and Modeling

Contracts were modeled on a monthly basis by product. For each product (7x24, 7x16, 6x16, 5x16, Off Peak, and Summer Super Peak) the total number of hours for that product for each month was calculated over the 10-year period.

Product definitions are as follows:

7x24: energy 7 days a week, 24 hours a day; also known as 'base' product

7x16: energy 7 days a week, 16 hours a day (hour ending 7 to hour ending 22)

6x16: energy 6 days a week (Monday to Saturday), 16 hours a day; also known as 'peak' product

5x16: energy 5 days a week (Monday to Friday), 16 hours a day.

Off Peak: energy for all day on Sunday, and 8 hours Monday to Saturday (hour ending 1 to hour ending 6 and hour ending 23 to hour ending 24). This is the balance of hours from 'peak' product

Summer Super Peak (SSP): energy for Monday to Friday, hour ending 12 to hour ending 20 (9 hours) from June to October.

Multiplying the capacity (MW) and the hours of use equals Mwh. However, there are times when this calculation cannot be used as easily as this.

1. A contract may be 'callable': the contract may be for 50 Mw of 6x16 capacity, but only for 15000 Mwh hours. For the month of March, 2001, there are 432 hours that fall into the 6x16 product category. Multiplying (50Mw x 432hours) = 21,600 Mwh. There are not enough contract hours to allow take advantage of all the capacity for the whole month. This type of contract allows CDWR to call on the power when it is needed. For the purposes of modeling, and tracking, the full capacity was entered and is used for reports requiring that info. To calculate total Mwh, we assumed the capacity was spread evenly across all hours of that product of that month.
2. Transmission losses were removed from the contracts prior to removing their energy from the net short. The PG&E load data provided to us already had transmission losses accounted for, so transmission losses were assumed to be 0%. SCE and SDG&E load data did not include transmission losses, so 2% was removed from the contracted Mwh.

Contracts under negotiation were modeled on the same typical week, such as a 7x24 product would have the same capacity modeled for all 168 hours. A 6x16 product would be modeled with the capacity being present during peak hours (for example Monday would be, hours 31-46 of a 168 hour week). As DWR entered into negotiations with generators, these are added to the IOU resources.

The model was structured to allow contracts to be toggled on and off. This allowed two or more versions of a contract to be modeled and each one looked at separately along with the rest of the portfolio under consideration to determine the effects of each variation of the negotiated contract.

The model was structured such that all dispatchable contracts were fully dispatched. If a contract was available for dispatch for a limited number of hours (for example only 4000 hours a year), then that contract would be modeled as being a take or pay contract for a 5x16 product since it most likely would be dispatched during peak hours.

Any IOU load not met by IOU resources, or contract purchases had to be made by future block purchases and spot purchases.

Demand Side Management (DSM)

In addition to the DWR Contracts that increase supply to meet the, DSM programs reduce the total load to meet the net short. Since they come at a cost, they are modeled similar to an energy contract that increases the resources. These programs were only modeled to occur in 2001 and 2002. These DSM programs modeled were:

1. Previous ISO contracts with industrial customers who have agreed, when called upon by the ISO, to reduce their energy use. The average cost for a Mwh under these programs is $575. This program occurs year round.
2. The Governor's 20/20 plan, which rewards consumers with a 20% rebate when they reduce their energy, use by 20% over the same month last year. Since this program is based on conservation, and there is a potential for customers to reduce energy use and still not meet the 20% threshold and therefore not receive any discount, this program is much less expensive and only costs a calculated $178 for a Mwh. This program occurs only during the months of June – October.

Future Purchase Determination

The resultant difference between IOU load and the sum of IOU Resources and DWR contracts makes up the Un-contracted Load, or Residual Net Short. In other words: Residual Net Short = IOU Load – IOU Resources – DWR Transactions - DSM

Calculations were made on the typical week to determine future block purchases that could be entered into and not create a situation where DWR had contracted for too much surplus power. Realizing that block purchases would never exactly match the forecasted load (due to time of day differences in supply and demand), the calculation of future block purchases estimated how large a block purchase to make to minimize the amount of spot purchases needed during the peak hours, and minimize the surplus power purchased during the shoulder hours.

Since power could be purchased in peak and off-peak blocks, a calculation was also done to minimize the amount of spot purchases needed in the off-peak hours, and also minimized the surplus in the off peak "reverse shoulder" hours.

These calculations could be done on a monthly basis separately for NP and SP transmission zones.

Initial Revenue Requirement Determination

Prior to the use of the more detailed ProSym model, all energy delivered into NP 15 was assumed in the model to meet the PG&E net short. All energy delivered into SP15 was used to meet the SCE and SDG&E net short. The allocation of costs between SCE and SDG&E was based entirely on the percent of net short each utility was responsible for inside the SP 15 transmission area.

There were times on a monthly basis where there was forecasted to be a considerable surplus of energy in SP15. An attempt was made to account for the transfer of this energy north to meet NP15 net short. It was assumed that only 80% of the available surplus could be transferred and the rest would be sold at 50% of the prevailing market price. This transfer was also limited to a capacity of 3000MW (nominal Path 15 capacity) and transmission losses of 2%.

The price of the transferred energy was determined to be the average cost of the contracted energy in SP15 for that month.

Total final cost for each utility was based on the contract costs for energy delivered to that utility (although DWR did not procure energy separately for customers of any one of the three IOUs), and an estimate of the spot purchases needed to be made to completely meet the net short. Spot purchases needed to meet the net short were split up into peak purchases, and off-peak purchases (standard 6x16 definitions of peak hours) with corresponding peak and off-peak prices. The sum of these costs comprised the net short energy cost component of the revenue requirement

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CDWR Total Average Cost for Net Short
(additional sensitivities)
All Current Contracts (5/11/01)

Year	Utility		Case 1a (High Spring, Early Summer Pricing)	Case 2a: Case 1a without Price Elasticity Demand Reduction	Difference from Case 1a	Case 3a: Case 1a without Price Elasticity Demand Reduction, without Load Curtailment Programs	Difference from Case 1a	Difference due to Loss of Load Curtailment Programs	Case 4a: Case 1a with Higher Energy Demand with Higher Summer Peak Prices (2001-2002)	Difference from Case 1a	Difference due to Incremental High Summer Peak Prices
2001	PG&E	cost	$ 4,847,035,773	$ 5,495,627,692	$ 648,592,119	$ 6,035,726,944	$ 1,188,691,171	$ 540,099,052	$ 5,831,461,276	$ 984,425,501	$ 335,833,382
		$/Mwh	$ 213	$ 223	$ 10	$ 244	$ 31	$ 22	$ 238	$ 23	$ 14
	SCE	cost	$ 2,649,951,496	$ 2,929,971,744	$ 280,020,248	$ 3,094,231,714	$ 444,280,219	$ 164,259,970	$ 2,964,307,669	$ 314,356,173	$ 34,335,926
		$/Mwh	$ 144	$ 149	$ 6	$ 161	$ 17	$ 12	$ 151	$ 7	$ 2
	SDG&E	cost	$ 812,031,006	$ 864,280,952	$ 52,249,945	$ 907,790,560	$ 95,759,552	$ 43,509,608	$ 873,382,647	$ 61,351,640	$ 9,101,595
		$/Mwh	$ 143	$ 149	$ 5	$ 159	$ 16	$ 11	$ 150	$ 7	$ 2
	STATE	cost	$ 8,309,018,276	$ 9,289,880,589	$ 980,862,312	$ 10,037,749,218	$ 1,728,730,942	$ 747,868,630	$ 9,669,151,491	$ 1,360,133,214	$ 379,270,902
		$/Mwh	$ 177	$ 185	$ 8	$ 202	$ 25	$ 17	$ 193	$ 15	$ 8
											$ -
2002	PG&E	cost	$ 4,372,226,941	$ 4,940,541,611	$ 568,314,670	$ 5,119,635,815	$ 747,408,874	$ 179,094,304	$ 4,981,873,288	$ 609,646,346	$ 41,331,775
		$/Mwh	$ 129	$ 133	$ 4	$ 138	$ 6	$ 5	$ 134	$ 5	$ 1
	SCE	cost	$ 3,379,491,907	$ 3,680,267,987	$ 300,776,080	$ 3,693,034,503	$ 313,542,596	$ 12,766,516	$ 3,715,924,436	$ 336,432,529	$ 35,856,449
		$/Mwh	$ 122	$ 126	$ 2	$ 126	$ 4	$ 2	$ 128	$ 4	$ 1
	SDG&E	cost	$ 1,197,579,155	$ 1,244,002,649	$ 46,423,494	$ 1,242,787,324	$ 45,208,168	$ (1,215,326)	$ 1,254,443,928	$ 56,864,773	$ 10,441,279
		$/Mwh	$ 121	$ 123	$ 2	$ 124	$ 3	$ 1	$ 124	$ 3	$ 1
	STATE	cost	$ 8,949,298,003	$ 9,864,812,147	$ 915,514,144	$ 10,055,457,642	$ 1,106,159,639	$ 190,645,494	$ 9,952,241,651	$ 1,002,943,648	$ 67,429,504
		$/Mwh	$ 125	$ 128	$ 3	$ 132	$ 6	$ 3	$ 130	$ 4	$ 1
2003	PG&E	cost	$ 3,432,885,653	$ 3,598,179,233	$ 165,293,580						
		$/Mwh	$ 94	$ 95	$ 1						
	SCE	cost	$ 3,091,756,033	$ 3,159,621,548	$ 67,866,515						
		$/Mwh	$ 96	$ 96	$ 0						
	SDG&E	cost	$ 1,047,248,902	$ 1,047,302,806	$ 53,904						
		$/Mwh	$ 95	$ 95	$ 0						
	STATE	cost	$ 7,571,890,588	$ 7,805,103,588	$ 233,213,000						
		$/Mwh	$ 95	$ 96	$ 0						
2004	PG&E	cost	$ 3,014,882,619	$ 3,076,115,442	$ 61,232,822						
		$/Mwh	$ 78	$ 78	$ 1						
	SCE	cost	$ 3,430,394,047	$ 3,456,542,952	$ 26,148,905						
		$/Mwh	$ 82	$ 82	$ (0)						
	SDG&E	cost	$ 1,184,268,406	$ 1,177,184,087	$ (7,084,319)						
		$/Mwh	$ 81	$ 81	$ (0)						
	STATE	cost	$ 7,629,545,071	$ 7,709,842,480	$ 80,297,409						
		$/Mwh	$ 80	$ 80	$ 0						
2005	PG&E	cost	$ 2,884,144,552	$ 2,912,398,310	$ 28,253,758						
		$/Mwh	$ 68	$ 68	$ 0						
	SCE	cost	$ 2,496,874,199	$ 2,510,074,134	$ 13,199,934						
		$/Mwh	$ 63	$ 63	$ 0						
	SDG&E	cost	$ 849,473,082	$ 848,281,355	$ (1,191,727)						
		$/Mwh	$ 63	$ 63	$ 0						
	STATE	cost	$ 6,230,491,833	$ 6,270,753,798	$ 40,261,966						
		$/Mwh	$ 65	$ 66	$ 0						

Year	Utility		Case 1a (High Spring, Early Summer Pricing)
2006	PG&E	cost	$ 2,918,862,680
		$/Mwh	$ 66
	SCE	cost	$ 2,494,487,526
		$/Mwh	$ 61
	SDG&E	cost	$ 821,414,770
		$/Mwh	$ 61
	STATE	cost	$ 6,234,764,976
		$/Mwh	$ 63
2007	PG&E	cost	$ 3,112,918,694
		$/Mwh	$ 66
	SCE	cost	$ 2,581,616,132
		$/Mwh	$ 62
	SDG&E	cost	$ 821,785,852
		$/Mwh	$ 61
	STATE	cost	$ 6,516,320,677
		$/Mwh	$ 64
2008	PG&E	cost	$ 3,276,345,591
		$/Mwh	$ 65
	SCE	cost	$ 2,688,611,439
		$/Mwh	$ 62
	SDG&E	cost	$ 833,892,214
		$/Mwh	$ 62
	STATE	cost	$ 6,799,049,244
		$/Mwh	$ 63
2009	PG&E	cost	$ 3,365,831,782
		$/Mwh	$ 65
	SCE	cost	$ 2,771,025,211
		$/Mwh	$ 62
	SDG&E	cost	$ 843,819,998
		$/Mwh	$ 62
	STATE	cost	$ 7,000,676,990
		$/Mwh	$ 63
2010	PG&E	cost	$ 3,642,065,502
		$/Mwh	$ 65
	SCE	cost	$ 2,892,381,447
		$/Mwh	$ 63
	SDG&E	cost	$ 865,339,142
		$/Mwh	$ 63
	STATE	cost	$ 7,299,806,091
		$/Mwh	$ 64

NOTE: 2001 data above is for May-Dec only

2001 Actual Statewide Data to Date

Jan (1-17)	cost	$ 549,141,593
	$/Mwh	$ 332
Feb	cost	$ 1,441,936,679
	$/Mwh	$ 304
Mar	cost	$ 1,601,464,301
	$/Mwh	$ 261
Apr	cost	$ 1,859,537,000
	$/Mwh	$ 263

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Tab: Sensitivity Summary (2)

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Case 1a (High Spring, Early Summer Pricing)

					Cost of Contracts	Contract Mwh	Cost of Remaining Net Short	Remaining Net Short Mwh
2001	PG&E	cost	$ 4,847,035,773	22,757,923	$ 1,223,831,126	7,802,224	$ 3,623,204,647	14,955,699.43
		$/Mwh	$ 213		$ 157		$ 242	
	SCE	cost	$ 2,649,951,496	18,443,004	$ 1,742,349,305	13,198,215	$ 907,602,191	5,244,789.14
		$/Mwh	$ 144		$ 132		$ 173	
	SDG&E	cost	$ 812,031,008	5,660,077	$ 540,319,053	4,120,251	$ 271,711,954	1,539,826.01
		$/Mwh	$ 143		$ 131		$ 176	
	STATE	cost	$ 8,309,018,276	46,861,004	$ 3,506,499,484	25,120,690	$ 4,802,518,793	21,740,315
		$/Mwh	$ 177		$ 140		$ 221	
2002	PG&E	cost	$ 4,372,226,941	33,807,240	$ 1,767,747,176	19,443,535	$ 2,604,479,765	14,363,704.26
		$/Mwh	$ 129		$ 91		$ 181	
	SCE	cost	$ 3,379,491,907	27,657,948	$ 2,387,144,152	21,031,366	$ 992,347,755	6,626,581.93
		$/Mwh	$ 122		$ 114		$ 150	
	SDG&E	cost	$ 1,197,579,155	9,921,982	$ 870,483,038	7,723,845	$ 327,096,118	2,198,137.71
		$/Mwh	$ 121		$ 113		$ 149	
	STATE	cost	$ 8,949,298,003	71,387,169	$ 5,025,374,366	48,198,746	$ 3,923,923,638	23,188,424
		$/Mwh	$ 125		$ 104		$ 169	
2003	PG&E	cost	$ 3,432,885,653	36,471,268	$ 2,737,735,491	30,848,903	$ 695,150,162	5,622,364.92
		$/Mwh	$ 94		$ 89		$ 124	
	SCE	cost	$ 3,091,756,033	32,587,218	$ 2,952,975,310	30,975,812	$ 138,780,723	1,611,405.97
		$/Mwh	$ 95		$ 95		$ 86	
	SDG&E	cost	$ 1,047,248,902	11,010,197	$ 1,000,346,041	10,456,898	$ 46,902,861	553,299.10
		$/Mwh	$ 95		$ 96		$ 85	
	STATE	cost	$ 7,571,890,588	80,068,684	$ 6,691,056,842	72,281,614	$ 880,833,746	7,787,070
		$/Mwh	$ 95		$ 93		$ 113	

Case 1a (High Spring, Early Summer Pricing)

Year	Utility	Item	Case 1a		Cost of Contracts	Contract Mwh	Cost of Remaining Net Short	Remaining Net Short Mwh
2004	PG&E	cost	$ 3,014,882,619	38,811,219	$ 2,924,507,745	37,653,607	$ 90,374,875	1,157,612.71
		$/Mwh	$ 78		$ 78		$ 78	
	SCE	cost	$ 3,430,394,047	42,078,209	$ 3,366,697,309	41,157,757	$ 63,696,738	920,452.53
		$/Mwh	$ 82		$ 82		$ 69	
	SDG&E	cost	$ 1,184,268,406	14,591,280	$ 1,167,340,835	14,343,031	$ 16,927,571	248,249.24
		$/Mwh	$ 81		$ 81		$ 68	
	STATE	cost	$ 7,629,545,071	95,480,709	$ 7,458,545,888	93,154,394	$ 170,999,183	2,326,314
		$/Mwh	$ 80		$ 80		$ 74	
2005	PG&E	cost	$ 2,884,144,552	42,300,989	$ 2,741,590,075	40,273,129	$ 142,554,477	2,027,860.64
		$/Mwh	$ 68		$ 68		$ 70	
	SCE	cost	$ 2,496,874,199	39,402,006	$ 2,360,376,947	37,441,923	$ 136,497,252	1,960,083.12
		$/Mwh	$ 63		$ 63		$ 70	
	SDG&E	cost	$ 849,473,082	13,483,204	$ 811,603,527	12,934,762	$ 37,869,555	548,442.26
		$/Mwh	$ 63		$ 63		$ 69	
	STATE	cost	$ 6,230,491,833	95,186,199	$ 5,913,570,549	90,649,813	$ 316,921,284	4,536,386
		$/Mwh	$ 65		$ 65		$ 70	
2006	PG&E	cost	$ 2,918,862,680	44,358,583	$ 2,533,699,694	39,293,905	$ 385,162,985	5,064,677.70
		$/Mwh	$ 66		$ 64		$ 76	
	SCE	cost	$ 2,494,487,526	40,631,188	$ 2,282,813,751	37,774,138	$ 211,673,775	2,857,050.67
		$/Mwh	$ 61		$ 60		$ 74	
	SDG&E	cost	$ 821,414,770	13,504,971	$ 763,178,434	12,716,290	$ 58,236,336	788,680.94
		$/Mwh	$ 61		$ 60		$ 74	
	STATE	cost	$ 6,234,764,976	98,494,742	$ 5,579,691,879	89,784,333	$ 655,073,097	8,710,409
		$/Mwh	$ 63		$ 62		$ 75	

Case 1a (High Spring, Early Summer Pricing)

Year	Utility		Case 1a (High Spring, Early Summer Pricing)		Cost of Contracts	Contract Mwh	Cost of Remaining Net Short	Remaining Net Short Mwh
2007	PG&E	cost	$ 3,112,918,694	47,327,190	$ 2,468,744,640	38,958,942	$ 644,174,054	8,368,248.19
		$/Mwh	$ 66		$ 63		$ 77	
	SCE	cost	$ 2,581,616,132	41,732,942	$ 2,311,384,929	38,105,955	$ 270,231,203	3,626,987.00
		$/Mwh	$ 62		$ 61		$ 75	
	SDG&E	cost	$ 821,785,852	13,404,827	$ 747;553,949	12,405,983	$ 74,231,903	998,843.87
		$/Mwh	$ 61		$ 60		$ 74	
	STATE	cost	$ 6,516,320,677	102,464,958	$ 5,527,683,518	89,470,879	$ 988,637,160	12,994,079
		$/Mwh	$ 64		$ 62		$ 76	
2008	PG&E	cost	$ 3,276,345,591	50,280,218	$ 2,425,279,261	39,075,936	$ 851,066,331	11,204,282.38
		$/Mwh	$ 65		$ 62		$ 76	
	SCE	cost	$ 2,688,811,439	43,289,804	$ 2,284,452,781	37,964,783	$ 404,358,658	5,325,020.91
		$/Mwh	$ 62		$ 60		$ 76	
	SDG&E	cost	$ 833,892,214	13,552,401	$ 723,566,976	12,098,654	$ 110,325,238	1,453,746.26
		$/Mwh	$ 62		$ 60		$ 76	
	STATE	cost	$ 6,799,049,244	107,122,423	$ 5,433,299,017	89,139,373	$ 1,365,750,227	17,983,050
		$/Mwh	$ 63		$ 61		$ 76	
2009	PG&E	cost	$ 3,385,831,782	52,235,352	$ 2,398,390,216	38,990,683	$ 987,441,566	13,244,669.09
		$/Mwh	$ 65		$ 62		$ 75	
	SCE	cost	$ 2,771,025,211	44,377,219	$ 2,291,727,732	38,023,898	$ 479,297,479	6,353,321.24
		$/Mwh	$ 62		$ 60		$ 75	
	SDG&E	cost	$ 843,819,998	13,638,218	$ 713,307,299	11,907,264	$ 130,512,699	1,730,954.53
		$/Mwh	$ 62		$ 60		$ 75	
	STATE	cost	$ 7,000,676,990	110,250,789	$ 5,403,425,246	88,921,844	$ 1,597,251,744	21,328,945
		$/Mwh	$ 63		$ 61		$ 75	

Case 1a (High Spring, Early Summer Pricing)

				Cost of Contracts	Contract Mwh	Cost of Remaining Net Short	Remaining Net Short Mwh
2010	PG&E	cost	$ 3,542,085,502	54,327,292	$ 2,373,135,535	38,661,187	$ 1,168,949,967	15,666,105.64
		$/Mwh	$ 65		$ 61		$ 75	
	SCE	cost	$ 2,892,381,447	45,755,451	$ 2,303,733,495	37,947,201	$ 588,647,952	7,808,250.33
		$/Mwh	$ 63		$ 61		$ 75	
	SDG&E	cost	$ 865,339,142	13,809,863	$ 704,988,856	11,681,722	$ 160,350,286	2,128,140.83
		$/Mwh	$ 63		$ 60		$ 75	
	STATE	cost	$ 7,299,806,091	113,892,606	$ 5,381,857,886	88,290,109	$ 1,917,948,205	25,602,497
		$/Mwh	$ 64		$ 61		$ 75	